Power System Security

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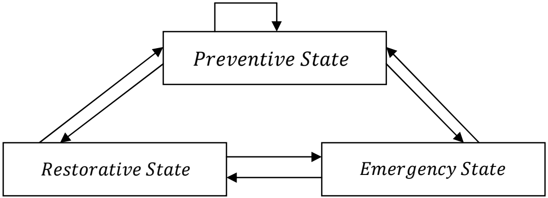
Outline

What is power system security?

Power system security may be looked upon as the probability of the system's operating point remaining within acceptable ranges, given the probabilities of changes in the system (contingencies) and its environment.

T.E. Dy Liacco, "The Adaptive Reliability Control System", IEEE Trans. PAS, Vol. PAS-86, No.5, May 1967, PP.517.531.

Dy Liacco first pointed out in 1967 that a power system may be identified to be operating in a number of states.



Figur: Operating States of the Power System

Preventive state

- The preventive state is actually the normal state. The term ‘preventive’ was used to stress the ‘Security’ aspect of the normal operation.
- Normal operating condition usually means that all the apparatus are running within their prescribed limits, and all the system variables are within acceptable ranges.
- The system should also continue to operate ‘normally’ even in the case of credible contingencies. The operator should ‘foresee’ such contingencies (disturbances) and take preventive control actions (as economically as possible) such that the system integrity and quality of power supply is maintained.

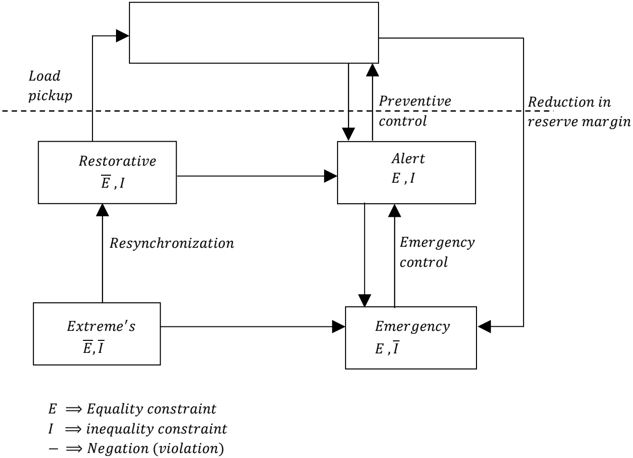
Emergency state

- The power system enters an emergency state when some of the components operating limits are violated; some of the states wander outside the acceptable ranges, or when the system frequency starts to decrease.
- The control objective in the emergency state is to relieve system stress by appropriate actions.
- Economic considerations become secondary at this stage.

Restorative state

- Restorative state is the condition when some parts (or whole) of the system has lost power.
- The control objective in this state is to steer the system to a normal state again by taking appropriate actions.

L. H. Fink and K. Carlsen, "Operating under stress and strain," *IEEE Spectrum*, March, 1978



Figur: State transition diagram (Fink and Carlsen)

State transition diagram, Fink, Carlsen,... contd.

- Power system operation can be described by three sets of generic equations: one differential, and two algebraic.
- Of the two sets of algebraic equations, one comprises of equality constraints(E), which is the balance between generation and load demand.
- The other set consists of inequality constraints (I) which ensure that the various components in the system and the states (e.g. voltages and currents) remain within safe or acceptable limits.

State transition diagram, Fink, Carlsen,... contd.

- If the generation falls below certain threshold, load increases beyond some limit, or a potentially dangerous disturbance becomes imminent, the system is said to enter the alert state.
- Though the equality (E) and inequality (I) constraints are still maintained, preventive controls should be brought into action to steer the system out of the alert state.
- If preventive control fails, or the disturbance is reverse, the system may enter into an emergency state, though the demand is still met by the generation, one or more component or state violate the prescribed operation limits. Emergency control actions should immediately be brought into action to bring the system back to the normal state.

State transition diagram, Fink, Carlsen,... contd.

- If the emergency control actions also fail, the system may enter extremis state which is characterized by disintegration of the entire system into smaller islands, or a complete system blackout.
- It may take anywhere between few seconds to few minutes for a system to enter an extremis state from a normal state.
- The restoration process however is very slow. It may take several hours or even days to bring the system back to normal.

Major components of security assessment

- System monitoring
- Contingency analysis
- Preventive and corrective actions

System monitoring

- The prerequisite for security assessment of a power system is the knowledge of the system states. Monitoring the system is therefore the first step.
- Measurement devices dispersed throughout the system help in getting a picture of the current operating state. The measurements can be in the form of power injections, power flows, voltage, current, status of circuit breakers, switches, transformer taps, generator output etc., which are telemetered to the control centre.
- Usually a state estimator is used in the control centre to process these telemetered data and compute the best estimates of the system states.
- Remote control of the circuit breakers, disconnector switches, transformer taps etc. is generally possible. The entire measurement and control system is commonly known as supervisory control and data acquisition (SCADA) system.

Contingency analysis

Once the current operating state is known, the next task is the contingency analysis. Results of contingency analysis allow the system to be operated defensively. Major components of contingency analysis are:

- Contingency definition
- Contingency selection
- Contingency evaluation

Contingency analysis...contd.

- Contingency definition involves preparing a list of probable contingencies.
- Contingency selection process consists of selecting the set of most probable contingencies in preferred; they need to be evaluated in terms of potential risk to the system. Usually, fast power flow solution techniques such as DC power flow are used to quickly evaluate the risks associated with each contingency.
- Finally, the selected contingencies are ranked in order of their security, till no violation of operating limits is observed.

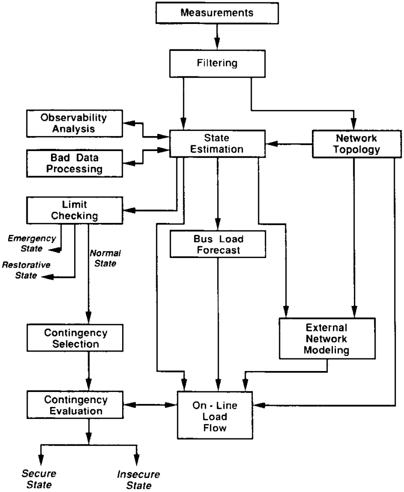
Preventive and corrective actions

- Preventive and corrective actions are needed to maintain a secure operation of a system or to bring it to a secure operating state.
- Corrective actions such as switching of VAR compensating devices, changing transformer taps and phase shifters etc. are mainly automatic in nature, and involve short duration.
- Preventive actions such as generation rescheduling involve longer time scales. Security-constrained optimal power flow is an example of rescheduling the generations in the system in order to ensure a secure operation.

On-line security assessment

- In earlier days, security assessment in a power system was mainly offline in nature. Predefined set of rules or nomographs were used to assist the operators in the decision-making process.
- However, due to the highly interconnected nature of modern power systems, and deregulated energy market scenarios, operating conditions and even the topology of a power system changes frequently. Off-line techniques for security assessment are therefore no- longer reliable in modern power systems.
- On-line security assessment techniques use near-real-time measurements from different locations in a power system, and continuously update the security assessment of the system.

N. Balu et.al., "On-line power system security analysis," Proc. of the IEEE, Vol 80, No. 2, Feb. 1992, pp. 262-280.



DC power flow

Active power flow between buses i and j is given by,

$$P_{ij} = \frac{V_i V_j}{X_{ij}} \sin(\theta_i - \theta_j) \tag{1}$$

Assuming $V_i = V_j = 1$ p.u., and $\sin(\theta_i - \theta_j) \approx (\theta_i - \theta_j)$, (since $(\theta_i - \theta_j)$ is usually very small),

$$P_{ij} \approx \frac{(\theta_i - \theta_j)}{X_{ij}} \tag{2}$$

Power injection at bus i therefore is given by,

$$P_i = \sum_{j=1}^{N} P_{ij} = \sum_{j=1}^{N} \frac{(\theta_i - \theta_j)}{X_{ij}} \tag{3}$$

DC power flow...contd.

Hence,

$$\frac{\partial P_i}{\partial \theta_i} = \sum_{j=1}^{N} \frac{1}{x_{ij}} \tag{4}$$

$$\frac{\partial P_i}{\partial \theta_j} = -\frac{1}{x_{ij}} \tag{5}$$

Now,

$$\Delta P_i = \frac{\partial P_i}{\partial \theta_1}\Delta\theta_1 + ... + \frac{\partial P_i}{\partial \theta_N}\Delta\theta_N \tag{6}$$

Iterative equations for power flow then become:

$$\begin{bmatrix} \Delta P_1 \\ . \\ . \\ . \\ \Delta P_N \end{bmatrix} = \begin{bmatrix} B_{11} & B_{12} & . & . & . & B_{1N} \\ . & . & . & . & . & . \\ . & . & . & . & . & . \\ . & . & . & . & . & . \\ B_{N1} & B_{N2} & . & . & . & B_{NN} \end{bmatrix} \begin{bmatrix} \Delta\theta_1 \\ . \\ . \\ . \\ \Delta\theta_N \end{bmatrix} \tag{7}$$

Or,

$$\Delta P = [B][\Delta\theta] \tag{8}$$

Linear sensitivity factors

- Analyzing in details a large number of contingencies is a difficult task.
- An easy (approximate) way to quickly compute any possible violation of operating limits is the one of linear sensitivity factors.
- Two such sensitivity factors for checking line flow violations are generation shift factors and line outage distribution factors.

Generation shift factors

They calculate the effect of change in generation on the line flows, as shown below:

$$a_{li} = \frac{\Delta f_l}{\Delta P_i} \tag{9}$$

where a_{li} is the linearized generation shift factor for the lth line for a change in output of ith generator; Δf_l is the MW change in power flow in the lth line; ΔP_i is the change in generation at the ith bus.

Generation shift factors...contd.

It is assumed here that the change in generation at the ith bus is picked up by the reference bus. The new values of power flows in each line can be found from:

$$f_l^{new} = f_l^{old} + a_{li}\Delta P_i; \;\; \forall l = 1, 2, \ldots, L \tag{10}$$

where f_l^{old} is the power flow in the lth line before the ith generator went out. Assuming P_i^{old} to be the output of the ith generator before fault, above equation can be expressed as,

$$f_l^{new} = f_l^{old} - a_{li}P_i^{old}; \;\; \forall l = 1, 2, \ldots, L; [\because \Delta P_i = -P_i^{old}]. \tag{11}$$

Generation shift factors...contd.

- Once the new values of flows are computed for all the lines, they are compared with corresponding line flow limits. Operators are 'alarmed' in case of any limit violations.
- In a practical power system, due to governor actions, the loss of generation at the bus i may be compensated by their generators throughout the system.
- A frequently used method is to assume that the loss of generation is distributed among participating generators in proportion to their maximum MW rating.

Generation shift factors...contd.

Therefore, the proportion of generation pickup by the jth generator is given by,

$$\gamma_{ji} = \frac{P_j^{\max}}{\sum\limits_{\substack{k=1 \\ k \neq i}}^{N_G} P_k^{\max}} \tag{12}$$

where P_k^{max} is the maximum MW rating of the kth generator; N_G is the number of participating generators; γ_{ji} is the proportionality factor for pickup on generating unit j when unit i fails.

The new line flows are then given by,

$$f_l^{new} = f_l^{old} + a_{li}\Delta P_i - \sum_{\substack{j=1 \\ \neq i}}^{N_G} (a_{li}\gamma_{ji}\Delta P_i) \tag{13}$$

Note: It is assumed here that no unit hits its generating limit.

Line outage distribution factor

Line outage distribution factors are used to quickly check line overloading as a result of outage of any transmission line, and are defined as follows:

$$d_{lk} = \frac{\Delta f_l}{f_k^{old}} \tag{14}$$

where d_{lk} is the line outage distribution factor for line l after an outage of line k; Δf_l is the change in MW flow in line l due to the outage of line k; f_k^{old} is the flow in line k before its outage.
The new value of line flow is given by,

$$f_l^{new} = f_l^{old} + d_{lk} f_k^{old} \tag{15}$$

Algorithm for contingency analysis